3.0 ALTERNATIVES

3.1 FACTORS USED IN SELECTION OF ALTERNATIVES

3.1.1 Alternatives Development and Screening Process

One of the most important aspects of the environmental review process is the identification and assessment of reasonable alternatives that have the potential for avoiding or minimizing the impacts of a proposed Project. In addition to mandating consideration of the No Project Alternative, the California Environmental Quality Act (CEQA) Guidelines Section 15126.6(d) emphasize the selection of a range of reasonable alternatives and an adequate assessment of these alternatives to allow for a comparative analysis for consideration by decision-makers.

The CEQA requires consideration of a range of reasonable alternatives to the Project or Project location that: (1) could feasibly attain most of the basic Project objectives; and (2) would avoid or substantially lessen any of the significant impacts of the proposed Project. An alternative cannot be eliminated simply because it is more costly or if it could impede the attainment of all Project objectives to some degree. However, the State CEQA Guidelines declare that an Environmental Impact Report (EIR) need not consider an alternative whose effects cannot be reasonably ascertained and whose implementation is remote or speculative. The CEQA requires that an EIR include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed Project.

This screening analysis does not focus on relative economic factors of the alternatives (as long as they are feasible) since the State CEQA Guidelines require consideration of alternatives capable of eliminating or reducing significant environmental effects even though they may “impede to some degree the attainment of project objectives or would be more costly.” Likewise, the question of market demand or project need is not considered.

3.1.2 Alternatives Screening Methodology

Alternatives to the proposed Project were selected based on input from the Applicant, the EIR preparers, and the public and local jurisdictions during the EIR scoping hearings. The alternatives screening process consisted of three steps:

Step 1: Define the alternatives to allow comparative evaluation.

Step 2: Evaluate each alternative in consideration of one or more of the following criteria:

- The extent to which the alternative would accomplish most of the basic goals and objectives of the Project;
- The extent to which the alternative would avoid or lessen one or more of the identified significant environmental effects of the Project;
- The potential feasibility of the alternative, taking into account site suitability, economic viability, availability of infrastructure, General Plan consistency, and consistency with other applicable plans and regulatory limitations; and
- The requirement of the State CEQA Guidelines to consider a "No Project" Alternative and to identify, under specific criteria, an "environmentally superior" alternative in addition to the "No Project" Alternative (State CEQA Guidelines, Section 15126.6(e)).

Step 3: Determine suitability of the proposed alternative for full analysis in the EIR. If the alternative is unsuitable, eliminate it, with appropriate justification, from further consideration.

Feasible alternatives that did not clearly offer the potential to reduce significant environmental impacts and infeasible alternatives were removed from further analysis. In the final phase of the screening analysis, the environmental advantages and disadvantages of the remaining alternatives were carefully weighed with respect to potential for overall environmental advantage, technical feasibility, and consistency with project and public objectives.

If an alternative clearly does not provide any environmental advantages as compared to the proposed Project, it is eliminated from further consideration. At the screening stage, it is not possible to evaluate potential impacts of the alternatives or the proposed Project with absolute certainty. However, it is possible to identify elements of the proposed Project that are likely to be the sources of impact. A preliminary assessment of potential significant effects of the proposed Project resulted in identification of the following impacts:

- Potential increase in air pollutant emissions, particularly during construction of the pipeline (Air Quality); also on-going operations, which have higher electrical demands;

- Potential change in the risk of an oil spill that would affect marine water quality, marine life, and commercial and recreational fishing (Water Resources, Biological Resources);

- Increased vessel traffic impacts to marine mammals and turtles due to drilling activities (Biological Resources);

- Potential impacts to terrestrial biological resources due to installation of the onshore pipeline (Biological Resources);

- Potential change in the risk of an oil spill that would affect terrestrial biological resources (Biological Resources); and

- Potential change in the risk of an oil spill that would affect recreation in the vicinity of the proposed Project (Recreational Resources).

There could also be some potential beneficial impacts particularly those associated with the abandonment of the Ellwood Marine Terminal (EMT) and the transportation of crude oil by pipeline instead of barge.

For the screening analysis, the technical and regulatory feasibility of various potential alternatives was assessed at a general level. Specific feasibility analyses are not needed for this purpose. The assessment of feasibility was directed toward reverse reason, that is, an attempt was made to identify anything about the alternative that would be infeasible on technical or regulatory grounds. The CEQA does not require elimination of a potential alternative based on cost of construction and operation/maintenance.

3.1.3 Summary of Screening Results

Potential alternatives were reviewed against the above criteria. A number of alternatives were eliminated based on their inability to meet most of the basic Project objectives or that were technically infeasible due to site-specific constraints. Those alternatives that were found to be technically feasible and consistent with the Applicant's objectives were reviewed to determine if the alternative had the potential to reduce the environmental impacts of the proposed Project.

Table 3-1 represents the evaluation and selection of potential alternatives to be addressed in the EIR. Those listed in the first column have been eliminated from further consideration (see rationale in Section 3.2, Alternatives Eliminated from Full Evaluation), and those in the second column are evaluated in detail in Section 4.0, Environmental Analysis, of this EIR and are described in detail below.

Table 3-1
Summary of Alternative Screening Results

Alternatives Eliminated from Consideration	Alternatives Evaluated in this EIR
Offshore Gas pipeline to Platform Grace/Gail	No EOF Modifications
Onshore sour gas pipeline to LFC	Processing on Platform Holly
Onshore Drilling Options	Las Flores Canyon Processing: Offshore Gas and Onshore Oil Pipeline
Bifurcated oil and gas processing locations	Las Flores Canyon Processing: Offshore Gas and Offshore Oil Pipeline
Offshore Crude Oil Pipeline to Rincon Onshore Separation Facility	No Project Alternative

Table 3-1 is not an exhaustive listing of potential options that could be arranged. With multiple pipelines, multiple destinations and processing locations, onshore and offshore locations for pipelines, there are numerous potential options and therefore alternatives. The list has been narrowed by addressing both the need for operational efficiency and the need for an alternative to reduce the potential significant impacts of the proposed Project. Therefore, an option has been included as an alternative which would lessen the safety impacts at the EOF (Holly processing), eliminate the safety impacts at the EOF (LFC processing), or reduce the spill impacts to the environment (offshore crude oil pipeline); however, additional environmental impacts may occur with the construction of a new offshore pipeline.

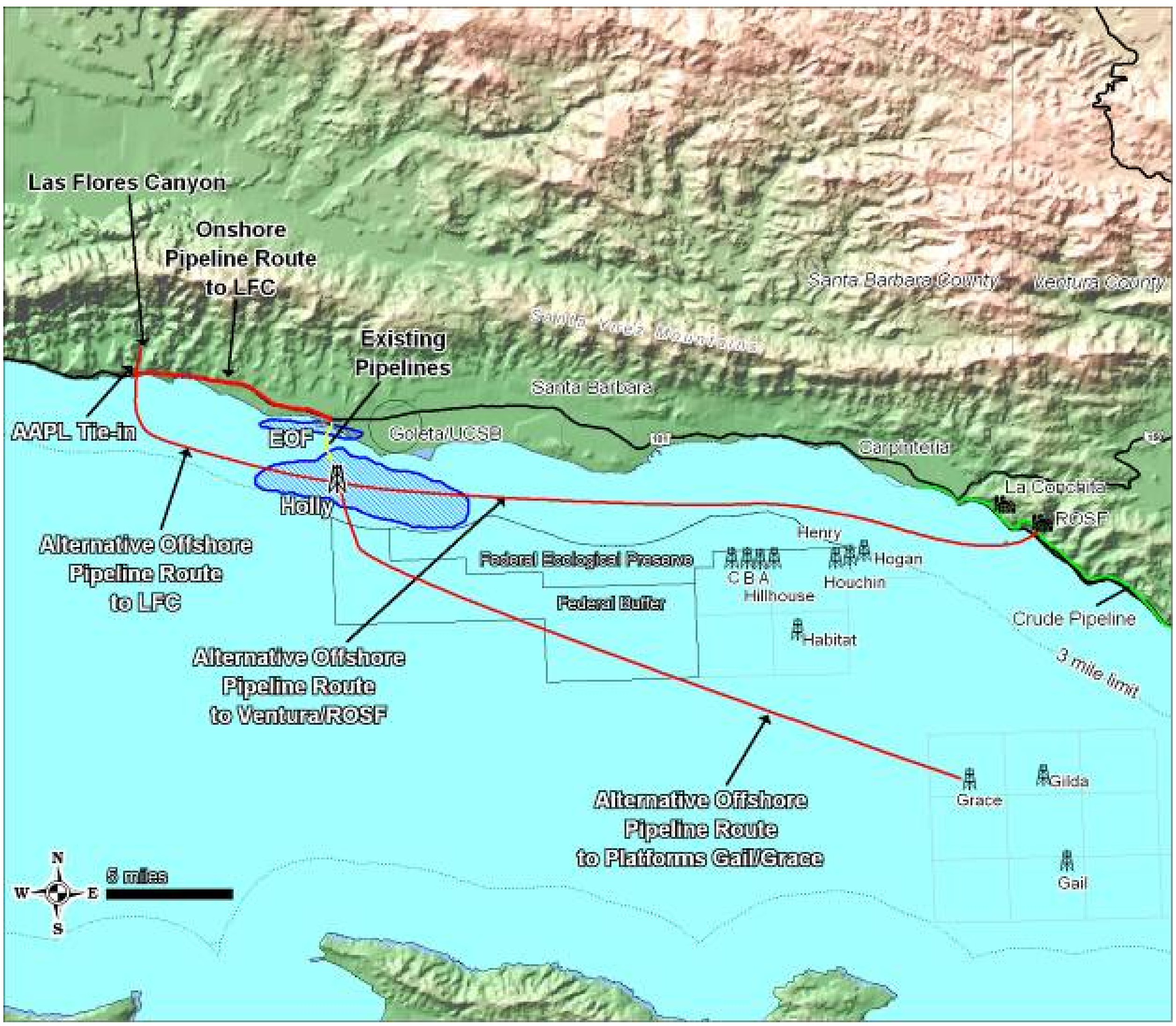
The LFC processing with offshore crude and gas pipelines has been included as an alternative because the operation of a new offshore pipeline, with its associated lower failure rate, might produce lower spill risks than operation of the existing Platform Holly pipeline; see Section 4.2, Hazards and Hazardous Materials.

3.2 ALTERNATIVES ELIMINATED FROM FULL EVALUATION

3.2.1 Offshore Crude Oil Pipeline to Rincon Onshore Separation Facility/Ventura

Construction of a 29-mile (46.7 km) offshore crude pipeline from Platform Holly to the Rincon Onshore Separation Facility (ROSF) in Ventura county for crude oil processing (see Figure 3-1) was considered as an alternative to the proposed Project. The oil produced from Platform Holly would be transported to the ROSF through a new 10-inch (0.25 m) diameter marine pipeline that would connect to the existing 22-inch (0.6 m) diameter sales oil line. Produced gas would continue to be processed at the EOF.

Figure 3-1
Alternative Locations



As shown in Figure 3-1, the pipeline would follow a route from Platform Holly through State submerged lands to the ROSF. This route is relatively flat and provides for the shortest length of pipe between Ellwood and the ROSF. It also avoids the Federal Ecological Preserve and the associated buffer zone in Federal waters.

The 10-inch (0.25 m) pipeline would leave Platform Holly heading southeasterly in State Waters within the Applicant's State lease PRC 3242.1. The route would continue easterly through State submerged lands where it would enter the parcel of State tidelands managed by Santa Barbara county. Santa Barbara county was given control of this section of State land by virtue of a 1931 tidelands grant from the State Legislature.

The crude pipeline would leave the above-mentioned parcel and continue through ungranted State tidelands where it would landfall through a 3,000 foot-long (914 m) directional drill. The directional drill would be made from the ROSF to an ocean outfall located approximately 1,000 feet (305 m) from shore in water depths ranging between 35 feet to 50 feet (11 m to 15 m) below mean sea level (MSL). The proposed 10-inch (0.25 m) pipeline would enter a pig receiver at the ROSF and be routed through a sales custody transfer meter and connected to the existing 22-inch (0.6 m) sales oil pipeline.

This alternative would require dehydration and stabilization of the crude oil at Platform Holly.

This alternative was eliminated due to the potential for crude oil spills from the offshore pipeline (due to the increased length and higher volume contained in that increased length), the potential for impacts to marine resources, and the resistance to such a proposed pipeline by the landowners, regulatory agencies, and other local agencies, when proposed in a prior application. Finally, landfall would be near the town of La Conchita in an area that is known to be geologically unstable. This geologic instability could lead to a higher risk of pipeline failures and oil spills.

3.2.2 Offshore Gas Pipelines to Grace/Gail

Construction of an offshore gas pipeline from Platform Holly to Platform Gail or Grace for gas processing (see Figure 3-1) was considered as an alternative to the proposed Project. The gas would be transported via a new six-inch (0.15 m) pipeline and would be constructed 28 miles to 34 miles (46 to 56 km) to Platforms Grace or Gail.

Crude oil would be transported via the existing pipeline to the EOF, where oil dehydration and processing would occur, and then through the proposed Project pipeline to the AACP tie-in near Las Flores Canyon (LFC). Water removed from the crude oil at Platform Holly would be injected at Platform Holly.

The installation and use of a new gas pipeline would allow for the abandonment of the existing gas processing at the EOF and allow for transportation of oil and gas to existing processing locations and to markets.

The pipeline would follow a route from Platform Holly south to Federal waters. The route would continue south of the Federal Ecological Preserve in Federal waters until it reached Platforms Gail or Grace.

Gas sweetening would occur on Platforms Gail or Grace, and the removal of gas liquids would take place at the Carpinteria Processing Facility (CPF) located in Carpinteria. The Platforms are already equipped with acid gas removal equipment.

Although moving the H_2S processing of the gas to offshore would reduce the risks associated with sour gas releases at the EOF, additional risks would be introduced at the CPF due to the increase in gas liquids removal. The gas liquids removed at the CPF would most likely exceed the amount of gas liquids that could be blended with the crude oil (as is the case currently at the EOF), thereby requiring the additional gas liquids to be trucked from the CPF. This would increase the risks at the CPF due to gas liquids storage as well as transportation in a densely populated residential and commercial area. Therefore, this alternative was eliminated from further consideration in the EIR.

3.2.3 Onshore Gas Pipeline to LFC

Construction of an 8.5 mile (13.7 km) onshore sour gas pipeline from Platform Holly to the LFC was considered as an alternative. The onshore sour gas pipeline would transport sour gas from Platform Holly to the EOF in the existing gas pipeline. A new pipeline would be installed adjacent to the proposed onshore crude oil pipeline, as described in the proposed Project EIR in Section 2.0, Project Description.

Crude oil would be transported via the existing pipeline from Platform Holly to the EOF, where oil dehydration and processing would occur; and through the proposed new, connecting pipeline to the AACP tie-in near LFC. Water removed from the crude oil at Platform Holly would be injected at Platform Holly.

The installation and use of a new onshore gas pipeline would allow for the abandonment of the existing gas processing at the EOF. Sour gas from Platform Holly would be processed at the LFC facilities.

The installation of a sour gas pipeline through residential areas and along Highway 101 would increase the risk to the public due to the potential for a sour gas pipeline leak or rupture and subsequent exposure of the public to the sour gas. Although this potential currently exists due to the EOF sour gas processing, the new pipeline route would pass close to existing residences and travel along Highway 101 before reaching the LFC area. Due to this concern, this alternative was eliminated from further consideration.

3.2.4 Onshore Drilling Options

Drilling of wells into the eastern section of the South Ellwood Field could technically be conducted from an onshore area as the field is close enough to shore so that directional drilling could reach the reserves. However, given a 3 to 4 mile (4.8 km to 6.4 km) reach limit for directional drilling, the only areas where drilling could be conducted onshore would be areas within UCSB or the city of Goleta. Based on previous unsuccessful attempts to drill from onshore locations, and current land use policies, this alternative was eliminated from further consideration.

3.2.5 Bifurcated Oil and Gas Processing Options

Alternatives were also eliminated which decreased the operational efficiency of the system. Operational efficiency is gained by processing the crude oil and the gas at the same location. For example, processing the crude oil at the EOF and gas at Platform Holly might reduce safety impacts at the EOF, but the air quality and energy use impacts would increase as there would no longer be a means of capturing waste heat gathered from combustion of “non-CARB spec” permeate-type waste gases and using this heat for crude treatment. In addition, stabilization of the gases and removal of hydrocarbons produces a gas liquids stream, all of which cannot be mixed with the crude oil due to vapor pressure constraints if the crude oil were processed at a different location. Under the Platform Holly processing alternative, the propane would be combusted in the process heater to allow heating of the crude oil and subsequent removal of the water in crude oil. If the crude oil were processed at a different location, this would complicate the processing arrangements and reduce overall efficiency, which would increase impacts in other areas.

3.3 ALTERNATIVES EVALUATED IN THE EIR

This section provides the descriptions of the alternatives evaluated in the EIR. A comparison of the production life under the various alternatives is provided in Table 3-2. In all cases, Platform Holly is designed to produce through 2040. The EMT would be abandoned and decommissioned in all cases except the No Project Alternative in which the facilities would be abandoned at the time of the offshore and onshore lease expirations.

Table 3-2
Production Life Comparison (Abandonment Year)

Facility	Proposed Project	Project Alternative				
		No Project	No EOF Modifica-tions	Processing on Holly	LFC Processing: Offshore Gas and Onshore Oil Pipelines	LFC Processing: Offshore Gas and Offshore Oil Pipelines
Platform Holly*	2040	2040	2040	2040	2040	2040
EOF	2040	2040	2040	2010**	2010	2010
EMT/Line 96	2010	2013-16***	2010	2010	2010	2010

* Platform Holly design life will be to at least 2040. Actual abandonment dates will depend on reservoir performance and commodity prices at the time.
** Some processes at the EOF under this alternative such as the sales gas booster compression system, crude oil storage and pumping, and electrical substation, would remain at the EOF site for the duration that Platform Holly is in operation.
*** The offshore lease with SLC expires in 2013 and the onshore lease with UCSB expires in 2016. Alternate transportation options would be pursued at that time.
Source: Venoco Application, February 2006.

3.3.1 No Project Alternative

Description

Under the No Project Alternative, production from Platform Holly and the EOF would continue under current operations; the lease boundary extensions beyond the existing oil and gas lease boundaries would not occur; drilling up to 40 new wells from Platform Holly would not occur; an onshore pipeline would not be constructed; the proposed modifications to the EOF and to Platform Holly would not be performed; and, decommissioning of the EMT would not occur in the near term. As the EMT offshore lease with CSLC expires in 2013 (should the currently proposed lease extensions be granted) and the onshore lease with UCSB expires in 2016, it is assumed that the EMT would be decommissioned as described in Section 2.0, Project Description, as a result of these lease terms. As a consequence, the EOF and Platform Holly would not have a mode to transport crude oil to markets beyond 2013 (offshore) and ultimately 2016 (onshore).

If oil and gas production at Platform Holly continues beyond the terms of the EMT lease without any additional approved time extensions, an alternative means of crude oil transportation would either need to be in place prior to decommissioning the EMT or production at Platform Holly would be stranded, at least temporarily. An analysis of alternative transportation options to the EMT is provided in the EMT Lease Renewal EIR (CSLC, 2006), which considered truck transportation or a pipeline similar to the onshore pipeline route as proposed by the Project and described in Section 2.0, Project Description. Note that the city of Goleta General Plan Policy LU 10.5c designates the city's support for oil transportation by pipeline.

Required Agency Approvals

Agency approvals including additional environmental review under the No Project Alternative would be required for any proposed alternative transportation mode that would be necessary as a result of the termination of the EMT lease and decommissioning of the EMT.

Energy Conservation and Alternative Energy Sources

The California Energy Commission (CEC), the California Power Authority (CPA), and the California Public Utilities Commission (CPUC) jointly adopted in 2005 the "Energy Action Plan II" (Plan) that listed joint goals for California's energy future (CEC 2005). The main goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound. The Plan also describes the priority sequence for actions to address increasing energy needs as (1) cost-effective energy efficiency and demand response, (2) renewable sources of power and distributed generation and (3) clean and efficient fossil-fired generation. The CEC 2007 Integrated Energy Policy Report (IEPR) adds achieving AB-32 greenhouse gases reduction goals to this list of priorities. The IEPR recommends a number of programs, including cost effective energy efficiency standards, renewable energy development, improved electricity infrastructure, and distributed power generation,

In order to provide information on other methods of generating the same level of energy production (crude oil and gas) proposed in the Project, an analysis was conducted to determine the level of alternative energy projects or programs that would be required to offset the amount of energy produced by the proposed Project. The proposed Project would produce an average of about 4,300 bbl crude oil per day over the life of the Project, assuming that the average additional production would equal about half of the peak additional production. Assuming an average gasoline production of 21.6 gallons per barrel of crude (CEC 2004 data), this would equate to an average of about 93,000 gallons of gasoline per day over the life of the Project. Crude oil is used to produce more fuel types than gasoline, such as diesel fuel, jet fuel, etc. However, it was assumed in this analysis that the primary driver of the consumption of crude oil is gasoline production.

The natural gas produced by the Project would average about 4.9 MMSCFD over the life of the Project, assuming that the average additional production would equal about half of the peak additional production. Assuming that all of this natural gas would be used to produce electricity, this could produce about 20 megawatts (MW) of electricity (based on the average efficiency of power plants in California).

Average gasoline consumption in California totals about 42 million gallons per day and the use in Santa Barbara county is estimated to be about 420,000 gallons per day (based on the number of registered cars in Santa Barbara County). Electrical generation in California totals 62.6 gigawatts (GW) of installed electrical generating capacity. Total capacity supplied to California is about 80 GW. Santa Barbara county uses about 1.2 percent of the total electricity supplied to the State (from CEC website statistics for 2005). Details of specific energy conservation alternatives and alternative fuels are provided below for reference to what those alternatives would have to produce in relationship to the Project. No conclusion statements are provided on this analysis.

Automobile Efficiency and Fuel Type

Gasoline consumption could be reduced by the equivalent of the amount produced by the Project, by replacing an estimated 91,000 automobiles with hybrid automobiles, e.g., Toyota Prius. This would constitute about three percent of the cars on the road in California.

Increasing the gas mileage of the average California car by 1.7 percent would also offset the gasoline produced by the proposed Project.

The proposed Project would produce about 22 percent of the gasoline used in Santa Barbara county. Replacing some of the gasoline with ethanol would require about 30 percent of this volume on an energy equivalent basis (as ethanol contains less energy than gasoline). Replacement of the gasoline supply in the county with 30 percent ethanol would reduce gasoline consumption by an amount equivalent to the proposed Project production levels.

Solar Energy

The amount of electricity that could be produced by the natural gas produced from the Project could be produced by installing close to half a million 200 watt photovoltaic solar panels on about 25,000 homes. Note that the solar panels would produce this level of energy for an estimated 25 years. However, the panels would only produce this amount of electricity during the daylight hours.

Solar energy currently makes up about 0.2 percent of the gross system power in the State of California (CEC 2007).

Electrical Efficiency

The amount of electricity that could be produced by the natural gas from the proposed Project could also be saved by increasing the efficiency of the end users of electricity. In Santa Barbara county, 75 percent of electrical consumption is by non-residential consumers, slightly higher than the state-wide average of 68 percent. State-wide, electrical consumption breaks down by sector to 32 percent residential, 37 percent commercial, 16 percent industrial, seven percent agricultural, and the rest miscellaneous users.

Lighting accounts for an estimated 25 percent of residential electrical consumption. By replacing inefficient light bulbs with more efficient bulbs through a replacement program, Santa Barbara county could reduce electrical demand by about 27 MW (assuming at least half of residential light bulbs are replaced), or in excess of the amount of electricity produced by the proposed Project.

Refrigerators account for an estimated 17 percent of residential energy use. By replacing older, inefficient refrigerators with newer, more efficient models, an estimated 3 MW could be saved.

Increasing the efficiency of industrial processes, through computer controlled equipment management, and replacing pump/compressor/HVAC units with more efficient models, electrical consumption could be reduced in the industrial sector. A program to replace industrial equipment and increase efficiency within Santa Barbara county by an estimated 10 percent would save an estimated 15 MW of generating capacity.

Air conditioners are large consumers of electricity during the hot summer months. Air conditioners' use represents approximately 30 percent of all electricity in the State during those months. Increasing the efficiency of air conditioners by replacing old air conditioners and increasing the building "envelope" efficiency through better insulation, ductwork and window type, would reduce electrical generation requirements during the hot months.

Natural Gas Use Efficiency

California consumes about 6.3 billion cubic feet (0.17 billion m^3) of natural gas per day. The Project's natural gas could be saved by increasing the efficiency of California's natural gas usage by about 0.08 percent.

The majority of natural gas power plants in California operate at efficiencies of 9,000 Btu/kWh to 11,000 Btu/kWh, with an average of 10,500 Btu/kWh (CEC 2007). More recent technology produces generating efficiencies at or below a 7,500 Btu/kW level, including the technology of combined cycle plants that utilize waste heat to generate additional power (CEC 2007). Only 17 percent of power plants in California produce power with efficiencies below 9,000 Btu/kWh. Calpine Corporation, which operates nearly 50 combined cycle power plants in California, indicates that their three largest combined cycle facilities operated at 7,300 Btu/kWh for all of 2003, including down times for maintenance. A substantial amount of power generating capacity could be realized by increasing the efficiency of power plants by re-tooling them or replacing older, less efficient power plants with more efficient plants. Replacing only one percent of the generating capacity of the most inefficient power plants (those with efficiencies above 11,000 Btu/kWh) with combined cycle, high efficiency plants would offset the proposed Project energy producing capabilities.

An estimated 44 percent of residential natural gas use is attributable to space heating. Increasing the efficiency of space heating through a replacement program of heating units and increasing the building "envelope" efficiency, by installing insulation, windows, duct-work, etc., would reduce space heating requirements. By increasing the space heating efficiency of all residences in Santa Barbara county by an average of 30 percent would offset the proposed Project natural gas production.

Wind Turbines

The equivalent level of electricity produced by combustion of natural gas could be generated through the use of wind turbines. The rated capacity of wind generation in California was approximately 2,100 MW at the end of 2005, generated by over 11,000 turbines, for a total of about 3.6 percent of California's electrical generating capacity. Wind turbine sizes in California range from small turbines less than 20 kW to massive turbines rated at 1.8 MW. GE currently makes turbines of 3.6 MW size and is developing turbines in the five to seven MW size with blades 140 meters in diameter. The majority of wind generating capacity in California is in the Altamont Pass (Bay Area) and Tehachapi Pass (Mojave). Wind resource maps produced by the California Energy Commission indicate that potentially good levels of wind resources exist in Santa Barbara county near Point Arguello (CEC 2007). A project proposed by Pacific Renewables for ranches southwest of Lompoc includes 60 to 80 wind turbines producing 80 and 120 megawatts of energy respectively. The EIR for this project is currently being prepared. Increasing the size of this wind project by about 20 percent would generate the equivalent amount of electricity as the proposed Project's natural gas production.

Geothermal Energy

Geothermal energy is produced by the heat of the earth and is often associated with volcanic and seismically active regions. California has 25 known geothermal resource areas, 14 of which have temperatures of 300°F or greater. California's geothermal power plants produce about 40 percent of the world's geothermally-generated electricity. The power plants have an installed capacity of about 2,500 megawatts -- producing five percent of California's total electricity in 2005. Major geothermal locations in the State include the Geysers (north of San Francisco), the Imperial Valley area east of San Diego, and the Coso Hot Springs area near Bakersfield. It is estimated that the State has a potential of more than 4,000 megawatts of additional power from geothermal energy, using current technologies (CEC 2007). Development of geothermal electrical power plants could offset the need for the proposed Project's natural gas to produce electricity.

Livestock Biogas Energy

Livestock generate a large amount of biological wastes that can be converted into gaseous fuel through digester systems and burned in generator engines to produce electricity and thermal heat energy. The GE Jenbacher engines provide specifications on the efficiency of biogas processes and an estimate of the amount of gas produced per livestock unit. A livestock unit is defined as about 1,200 pounds of livestock (500 kg), or the equivalent of about one cow. Based on the use of the GE Jenbacher generator sets, it would take a population of about 50,000 cows (or livestock units) to generate the equivalent amount of electrical energy that would be produced from the proposed Project. There are an estimated 1.7 million dairy cows in California, 60 percent of them on high-density feed lots, which are ideal locations for generating biogases, located primarily in Merced, Tulare, San Bernardino and Stanislaus counties. This system would also produce a substantial amount of thermal energy from the cogeneration side of the system for use in the livestock and farming processes.

3.3.2 No EOF Modifications

Description

If the proposed upgrades to the EOF do not meet the requirements for a Limited Exception Determination (LED) by the city of Goleta, then no modifications would be allowed at the EOF without a General Plan Amendment to change the property's land use designation and a rezone. Such applications would ultimately be decided upon by the voters of the city of Goleta under Section 35-150.1 of the City of Goleta Municipal Code. LEDs are made by the planning commission and are based on the procedures and findings contained in Section 35-161.7 of the city's Coastal Zone Ordinance. Section 35-161.7 states that an exception to the prohibition of modifications to industrial facilities in non-conformance to the zoning requirements can be made if the Project demonstrates and verifies "*the improvement's public health and safety benefit or environmental benefit*". Findings specific to a LED would include the following:

1. The improvement has a demonstrable public health and safety, or environmental benefit (e.g., would reduce the risk of a hazardous material spill or reduce air emissions);
2. The improvement does not result in any new un-mitigated significant environmental impacts;
3. The improvement does not result in an increase in the overall intensity of use beyond the existing permitted use (e.g., output/throughput per day) or, for facilities where no permits exist, would not increase the overall intensity of use beyond the current operating limits;

4. The improvement does not extend or expand the existing developed industrial site boundary within a parcel;

5. The improvement does not result in an expansion or extension of life of the nonconforming use due to increased capacity of the structure dedicated to the nonconforming use, or from increased access to a resource, or from an opportunity to increase recovery of an existing resource. Any extension in the life of the nonconforming use affected by the improvement results solely from improved operational efficiency, and is incidental to the primary purpose of improving public health and safety or providing an environmental benefit;

6. The improvement does not allow for processing of "new production" as defined in Section 35-154; and

7. If prior LEDs have been made for the same nonconforming use under this section, the successive LEDs cumulatively provide a public health and safety or environmental benefit.

The proposed EOF upgrades, which include the installation of a PSA system, backup compressor and associated modifications to the gas liquids systems and the LPG/NGL bullets, sulfur separation repairs and controls/monitoring upgrades would not take place under this alternative. In addition, power generation would not be installed. This alternative assumes that these modifications would not be performed.

Under the no EOF modifications alternative, the proposed offshore improvements and drilling program would continue as described in Section 2.0, Project Description. EOF modifications to allow for the tie-in of the new power cable and modifications to the two-inch pipeline would also be included as part of this alternative.

Required Agency Approvals

Agency approvals necessary under this alternative would include permits for any improvements at the EOF, if allowed, as well as approvals related to the EMT decommissioning and the offshore improvements. These would include:

- City of Goleta;
- CSLC;
- California Coastal Commission;

- California Department of Fish and Game;
- Regional Water Quality Control Board; and
- Santa Barbara County.

3.3.3 Processing on Platform Holly

Description

Processing of gas and crude oil is currently done on both Platform Holly and at the EOF. Platform Holly crude oil processing is limited to primary water and crude oil emulsion separation with the resulting water being injected into water injection wells. The resulting crude oil emulsion is pumped to the EOF. Platform Holly gas processing is currently limited to gas/emulsion separation, compression and dehydration using a glycol system with some gas being injected into injection wells, or used for gas lift, and the remaining gas being sent to the EOF for processing and sale. The two compressor trains include the Ingersol Rand compressors which compress all of the produced gas to about 220 psig (1.5 MPa-g) for dehydration and treating at the EOF; and the White-Superior compressors which compress some of the gas to 2,000 psig (13.7 MPa-g) for gas lift and re-injection.

This alternative would involve moving the gas and crude oil processing from the EOF to Platform Holly. It would entail the following components:

- Installation of crude dehydration and stabilization equipment on Platform Holly;
- Installation of an H_2S removal amine system on Platform Holly;
- Installation of a gas liquids removal system (LTS) on Platform Holly;
- Installation of utilities, such as process heating, water treatment, and propane refrigeration systems on Platform Holly;
- Installation of power generation equipment on Platform Holly; and
- Removal of associated equipment at the EOF.

Some processes would remain at the EOF, including crude oil storage and pumping, the electrical substation and sales gas compression. The crude pipeline to the AACP would still be installed for transporting the crude oil to area refineries. Gas processed at

Platform Holly would continue to be transported by pipeline to the Gas Company tie-in near the Bacara Resort. The proposed Project also includes power generation at the EOF which, under this alternative, could either be not installed, or installed at the EOF, or installed at Platform Holly. Please see Appendix C for a plot plan of the EOF under this alternative.

In February and December, 2001, the Applicant submitted an application to the CSLC and the county of Santa Barbara to fully develop the South Ellwood Field by expanding the lease boundary, transporting crude oil/emulsion to Ventura through an offshore pipeline, and conducting all gas processing at Platform Holly. The EOF would have been decommissioned except for the electrical substation, the control room and the sales gas compression. The 2001 application included extensive engineering analysis of the equipment and modifications that would be required at Platform Holly, including spacing, deck and jacket modifications, and approximate costs. Much of the 2001 analysis has been used in the following alternative discussion.

This alternative is also similar to the relocation option identified in the 2001 Santa Barbara county amortization analysis, which included gas processing and crude oil treatment on Platform Holly with crude oil transportation via pipeline to the AACP. Based on the economics of the year 2001 when crude oil and gas had substantially lower prices than at present, this alternative was determined in the amortization study to be the only economically feasible relocation option for the EOF and the EMT. The economic feasibility issue may have shifted significantly with the increase in oil prices, allowing for the feasibility of other alternatives as presented in this document. However, review of this alternative continues to be relevant to this environmental impact analysis and is provided below.

As in the proposed Project, Section 2.0, Project Description, construction of the crude oil pipeline from the EOF to the AACP, decommissioning of the EMT and Line 96; and the offshore improvements would still take place.

Each of the processing components is discussed below.

Platform Holly Crude Oil Processing

Processing of crude oil at Platform Holly would involve removal of water at Platform Holly and injection of all of the water into an injection well at the platform. Current operations at Platform Holly involve the removal of the majority of water (about 70%) from the emulsion in the existing 3-phase separators and injection of the water into an injection well. Current EOF crude oil processing involves the removal of additional water and stripping the crude oil to remove some of the residual H_2S. Stripping involves passing sweet gas through the crude oil to remove some of the residual H_2S. EOF crude oil, once fully processed, has a water content of less than three percent water. Additional equipment and processes would need to be installed at Platform Holly in order to reduce the crude oil water content to below three percent. The various offshore components are summarized in Table 3-3.

Table 3-3
Platform Holly Processing Alternative Components

Option	Platform Holly Processing	EOF Modifications
Crude: Offshore crude oil processing, pipeline to EOF and AACP.	Crude water dehydration and stabilization. Deck space: 300 ft² to 400 ft² (28 m² to 37 m²).	Remove crude stripping, water separation/heating. Crude storage, pig processing and pumping would remain at the EOF.
Gas: sulfur and CO_2 removal offshore	Amine unit: deck space: 700 ft² to 800 ft² (65 m² to 74 m²). Additional injection wells drilled.	Remove sulfur and CO_2 removal systems.
Gas: gas liquids removal.	LTS system: 400 ft² to 500 ft² (37 m² to 46 m²), gas liquids added to crude oil, stabilizer gas used in process heater/power generation.	Remove gas liquids recovery system including tanks. Remove propane storage for refrigeration.
Utilities.	Therminol: 200 ft² (19 m²). Water treatment: 400 ft² to 500 ft² (37 m² to 46 m²). Propane refrigeration: 200 ft² to 300 ft² (19 m² to 28 m²).	Removal of Therminol, heaters, water treatment facilities. Control building and electrical substation would remain.
Compression.	Production, acid gas, vapor recovery, stabilizer gas: utilize existing compression. 500 ft² (47 m²) net increase	Removal of all compression systems except final sales gas compression.
Power generation.	Up to 10 MW of power generation, with turbines or generator sets, and cogeneration.	No changes.

Oil dehydration on Platform Holly would be achieved by utilizing the existing three-phase separator and installing additional dehydration facilities including:

- Oil heater/exchanger, using Therminol to heat up the crude oil and remove some of the water (primary separation);

- Heat exchangers, to capture some of the treated crude's thermal energy and transfer it to the incoming crude;

- Degasing vessel to allow some residence time for trapped gases to flash off from (come out of) the crude oil;

- Hydrogen Sulfide stripping column, to remove some of the residual H_2S; and

- Electrostatic treater, to enhance gravity separation of the water from the crude oil.

Historically, crude oil H_2S levels, before stripping at the EOF, have ranged from 12 ppm to 115 ppm and averaged 43 ppm in 2005 (Santa Barbara County APCD 2007). A stripping column on Platform Holly would be necessary for the crude oil to meet the AACP crude specifications of 10 ppm.

The addition of the above listed crude processing equipment on Platform Holly would eliminate the need for crude oil/emulsion treatment at the EOF.

This alternative assumes that the onshore pipeline is constructed with a tie-in to the AACP, as described in Section 2.0, Project Description. Intermediate oil storage would be retained at the EOF. The existing two 2,000 bbl oil storage tanks at the EOF would be sufficient for this purpose. In addition, crude pumping from the EOF to the AACP and pig catchers (from Platform Holly) would also remain at the EOF to allow for pigging the pipeline between the EOF and Platform Holly. Pig launchers would need to be installed on the crude oil line at the EOF for pigging between the EOF and the AACP tie-in.

Deck spacing required for the installation of the crude oil processing equipment on Platform Holly is estimated to be about 300 ft^2 to 400 ft^2 (28 m^2 to 37 m^2).

Platform Holly Natural Gas Processing

Processing natural gas at Platform Holly could involve a number of equipment additions and modifications to Platform Holly. These would include adding the following equipment:

- H_2S and CO_2 removal/gas sweetening;

- Gas liquids removal;

- Utilities and support modifications, including refrigeration, Therminol heating system, water treatment, etc.; and

- Compression and transportation.

Each of the gas processing requirements is discussed below.

Platform Holly Gas Sweetening – Amine System

This alternative would require installation of H_2S and CO_2 removal at Platform Holly. The H_2S and CO_2 removal equipment would be removed at the EOF. Both H_2S and CO_2 are considered to be acid gases.

This alternative would involve the installation of amine equipment to provide for offshore separation of the H_2S and CO_2 from the produced gas stream, and to produce an acid gas stream that would be disposed of using existing and possibly new acid gas injection wells into the reservoir formations. Other platforms in the area, including the Point Arguello platforms (PXP), the Santa Ynez Unit (SYU) platforms (ExxonMobil), Platform Habitat (Dos Cuadras Offshore), and Platform Gail (the Applicant), utilize amine based H_2S removal systems.

Amine systems operate on the principal that an amine solution will absorb H_2S, CO_2 and other sulfur compounds from the gas and then release the absorbed gases at elevated temperatures. Aqueous solutions of alkanoamines (amines) are commonly used in gas processing and refining operations to remove acid gas (namely H_2S and CO_2) from natural gas or other hydrocarbon streams.

Amine systems typically include the following equipment:

- Absorber/contactor column, where the sour gas and the amine solution make contact;

- Amine flash tank, where gas liquids absorbed by the amine are flashed off;

- Amine regeneration unit and reboiler, where the H_2S and CO_2 are removed from the “rich” amine solution by heating to produce “lean” amine solution, which is returned to the absorber/contactor; and

- Various exchangers, storage tanks, pumps and filters;

Untreated fuel gas enters from the lower portion of the absorption column and exits from the top of the column with acid gas removed, while a stream of "lean" amine solution is pumped into the column from a location near the top, cascading down the column contacting the gas stream and absorbing acid gas. The absorber (or contactor) is equipped with devices such as valve trays, sieve trays or packings to promote the necessary contact between the gas stream and the absorbing liquid.

The "rich" amine solution leaves the absorption column from the bottom for the regeneration operation. The rich solution is first depressurized from the absorber pressure down to nearly atmospheric pressure in a flash tank to remove the hydrocarbon components co-absorbed in the solution. The rich solution is then heated in a lean/rich heat exchanger and pumped into the regeneration unit. The regeneration unit is equipped similarly to the absorption column with contacting trays. In the regeneration unit, heat is supplied to the system by a heating medium such as hot oil, Therminol (a synthetic fluid) or steam in the reboiler to heat the amine solution to the desired regeneration temperature and to provide sufficient heat to desorb the acid gas. The operating temperature in the reboiler and the amount of heating, along with the amine properties and flow rate, determines the residual acid content in the lean amine solution and consequently the removal efficiency.

The lean amine stream stripped of acid gas is cooled by the rich amine solution in the lean/rich heat exchanger down to approximately ambient temperature before it again enters the absorber.

The acid gas can be compressed and injected through wells into sub-surface reservoirs or the acid gas can be further processed to produce elemental sulfur (see below). The acid gas quantities are a function of the composition of the gas produced from the South Ellwood Field wells. Currently, acid gas levels in the field are approximately 15 percent CO_2 and a little less than two percent H_2S. The Applicant indicated in their 2001 application that CO_2 levels in the produced wells are anticipated to be on the order of five percent. Assuming the higher composition, acid gas production rates are estimated to be about 2.5 MMSCFD (0.07 million m^3) of acid gas, or about 0.9 BCF per year (25 million m^3), during peak production levels of 13 MMSCFD (0.37 million m^3) of produced gas.

The amine system would require heat input in order to regenerate the amine solution. The heat could be produced through combustion of the sweet gas in a process heater, through a cogeneration type system or the use of electric heating coils.

Deck space requirements for an amine system are estimated to be between 700 ft^2 to 800 ft^2 (65 m^2 to 74 m^2).

Platform Holly Gas Sweetening – High Slip Amine System

Due to reservoir volume limitations, it might be necessary to limit the acid gas flow stream to sulfur compounds that are removed by the amine plant, and to minimize the amount of carbon dioxide (CO_2) that would be injected into the Rincon formation. The CO_2 in the gas would then be removed using a membrane system and would be used in the process heater (similar to the proposed Project design at the EOF). This could be achieved through the use of a “high slip” amine, which permits the unhindered passage of CO_2 with the sweetened gas and thereby reduces the amount of acid gas that would require disposal.

The Applicant indicates in their 2001 applications that the “high slip” amine system would not be applicable to the Platform Holly-produced gas because certain produced gas constituents, such as traces of carbonyl sulfide and mercaptans, could cause interference with the amine reactions and prevent “high slip” reactions from occurring.

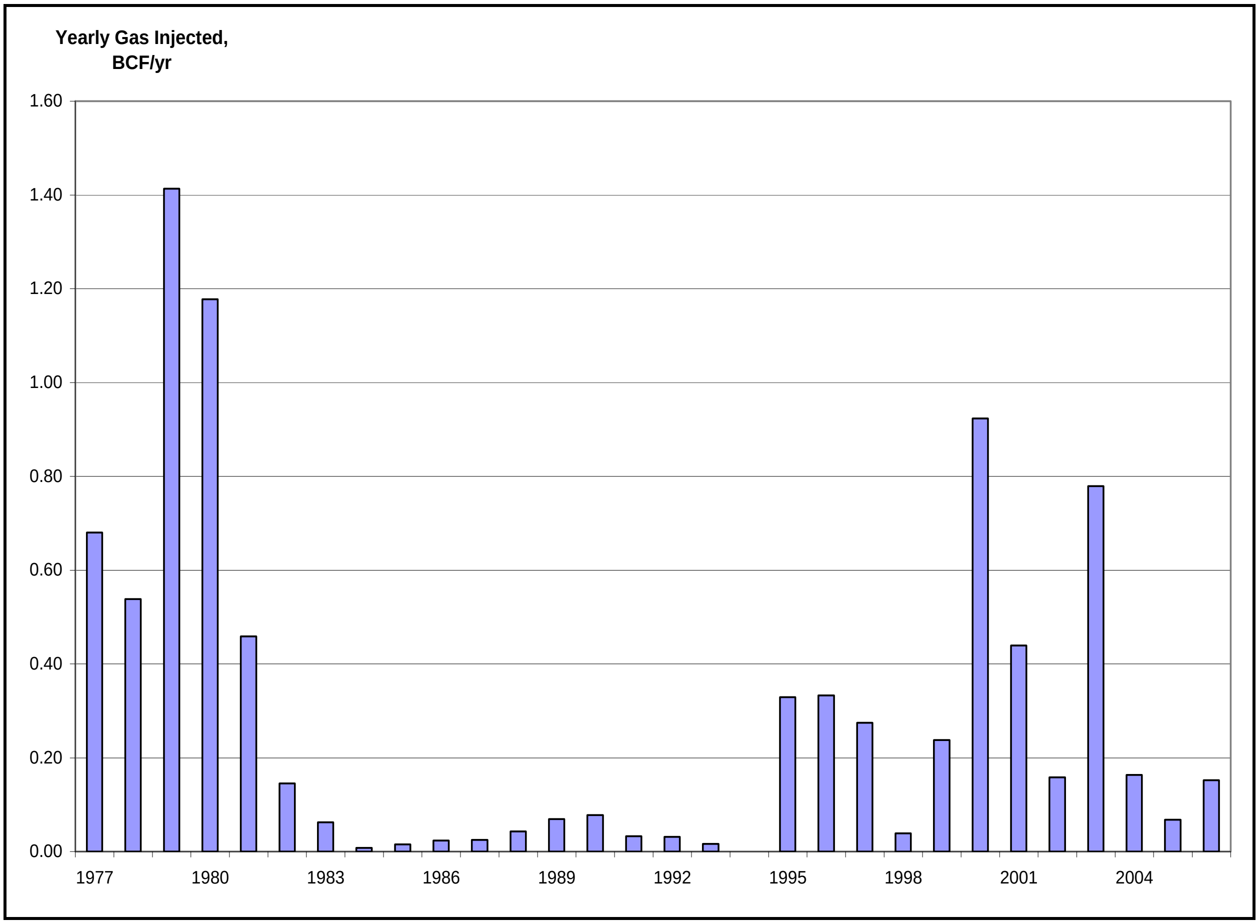
Although “high slip” might not be applicable, a certain amount of slip could be achieved through effective amine system design (Bryan 2006) that could reduce the amount of acid gas injection. The remaining CO_2 would then be removed with a membrane system on the platform and the permeate gas would be used in the process heater to provide heat to the platform. This option would need to be explored with design specifics by a vendor to ensure its applicability and effectiveness, but it is one option that could reduce the amount of acid gas needed to be injected offshore.

Acid Gas Disposal

Injection of the gas into the Rincon formation is currently conducted at Platform Holly when the EOF is not capable of processing all of the gas. Information available from the California Division of Oil, Gas, and Geothermal Resources (DOGGR 2007) indicates that injection into the South Ellwood Field has averaged about 0.30 BCF per year (8.5 million m^3) since 1977. Figure 3-2 shows the historical levels of injection into the South Ellwood Field.

The Applicant’s 2001 application indicated that injection rates would be sustainable between 2.5 MMSCFD and 4.2 MMSCFD, (0.07 million m^3 to 0.12 million m^3) or 0.90 BCF per year to 1.5 BCF per year (25 million m^3 to 42 million m^3). Historically, injection has occurred into the Rincon formation at levels approaching 1.0 BCF per year (28 million m^3).

Figure 3-2
Historical Injection into the South Ellwood Field



Source: DOGGR 2007

Additionally, new injection wells could be drilled into other locations in the Rincon to accept the necessary injection volume or allow for some additional storage. The Applicant has been exploring the possibility of drilling into the Sespe and Vaqueros formations for additional production. The Sespe and Vaqueros formations have historically produced as much as 3.6 BCF (102 million m^3) of gas from wells drilled in the Coal Oil Point area (Venoco 2003). Wells were drilled by ARCO from lease PRC 129 into the Vaqueros formation. The Applicant's well number one on lease PRC 421 is drilled into the Vaqueros and remains currently idle. Well number 15 on Platform Holly is drilled into the Sespe formation and has produced as recently as 2006 (DOGGR 2007). These reservoirs might be able to accept some gas injection. However, the ability of these reservoirs and formations to accept injected gas is unknown at this time and additional studies would need to be conducted.

For the purposes of this study, it is assumed that the existing Rincon formations and additional reservoirs could dispose of up to 1.0 BCF per year (28 million m^3) of gas.

Another possibility is the use of sulfur recovery which would be installed on Platform Holly to recover the sulfur from the gas. The amount of sulfur generated would be close to five million pounds (2.3 million kg) per year, or about six long tons per day (LTD) (6.5 metric tons), which would necessitate the use of special tanker-type boats to haul the sulfur to shore, and then the installation of offloading and handling equipment at a nearby port area. The equipment requirements for sulfur removal are fairly large, although some on-platform systems have been developed that are relatively compact (World Oil 1998). However, due to the need for special vessels and the spacing requirements, this was not considered a feasible option.

<u>Platform Holly Gas Liquids Removal</u>

The removal of H_2S and CO_2 from the gas would still be insufficient to allow the gas to be sold directly to The Gas Company, since the gas would still contain heavier hydrocarbons. These hydrocarbons would have to be removed from the gas. This would require the installation of low temperature separation (LTS) and stabilization equipment on Platform Holly.

An LTS system would most likely utilize a propane refrigerant to cool the gas stream to about -30° F (-34° C), at which point gas liquids (propane, butane, ethane, etc.) would drop out of the gas stream. The resulting gas liquids would then be stabilized by removing the lightest hydrocarbons to be pumped into the crude oil stream and transported to the AACP (as per the proposed Project). Stabilized gas would be combusted in the process heater and/or placed back into the sales gas stream up to the allowable gas specification limit.

An LTS system would include the following equipment:

- Propane refrigeration system, including propane storage, compression and exchangers, to provide the cooling;
- Glycol storage and injection system, to inject glycol into the gas stream to absorb residual water;

- Chiller vessel, for cooling of the gas stream;
- Glycol separation and glycol reboiler, to regenerate the glycol and remove the water using a Therminol heating medium; and
- Associated exchangers, tanks, piping, valves, filters and controls.

In addition, a condensate stabilizer would be installed to stabilize the gas liquids, remove the light ends from the gas liquids (i.e., the propane), and ensure that the vapor pressure of the gas liquids remains below 60 psia. These lighter ends would then be either routed as fuel for the platform heaters or electric generators, or sent back to the sales gas stream.

The propane refrigeration system would require an estimated 200 ft^2 to 300 ft^2 (19 m^2 to 28 m^2) of space on the Platform. The LTS skid mounted system would require an estimated 400 ft^2 to 500 ft^2 (37 m^2 to 46 m^2) of deck space.

Platform Holly Gas Dehydration

Water is currently removed from the gas at Platform Holly using a glycol system. This system would be modified and incorporated into the proposed LTS system to dehydrate the gas produced from the proposed Project.

Platform Holly Gas Compression

Compression requirements on the platform would include vapor recovery compression, produced gas compression, stabilizer gas compression, and acid gas compression.

Platform Holly currently has compressors for production gas, vapor recovery, and gas lift. Some modifications to the compression system would be required as the gas lift compressors could be used for injection of the acid gas. Gas lift compressors would no longer be required as the wells would utilize down-hole pumps instead of gas lift. Modifications to the gas lift compressor might be needed in order to accommodate the acid gas.

The vapor recovery system might need to be expanded as it would receive gas from the seep tents, the oil surge vessel, the lean amine system, and the Therminol system. The compressor would be sized to handle 2.3 MMSCFD (0.07 million m^3) to 70 psig (0.5 MPa-g). The system would have scrubber vessels and be equipped with a 400 hp electric motor. The discharge from the vapor recovery compression would be placed into the production gas stream.

Modification of the production compressors would allow for the gas to be compressed to higher pressures than current operations (about 500 psig [3.4 MPa-g]) for processing in the amine and LTS systems.

The acid gas compressors would compress the acid gas from the amine plant for injection into the injection wells and the respective reservoir. The compressor would compress between 2.5 MMSCFD and 4.2 MMSCFD (0.07 million m^3 to 0.12 million m^3) of acid gas to 1,800 psig (12.4 MPa-g).

A stabilizer gas compressor would need to be added which would compress the light ends from the LTS system gas liquids stabilizer to the 500 psig (3.4 MPa-g). The 500 psig is the required pressure for insertion into the sales gas stream to be sent to shore or as feed gas to the process/Therminol heater or generators. The compressor would be sized to handle up to 1.1 MMSCFD (0.03 million m^3) which can be accomplished with a 60 hp electric motor.

The deck spacing requirements for compression would be minimal except for the addition of the stabilizer gas compressor. This would total an estimated 500 ft^2 (47 m^2) increase.

Platform Holly Utilities and Additional Modifications

Utilities and additional modifications to Platform Holly and the pipelines to shore would include the following:

- Therminol system;
- Water treatment;
- Water deionization system;
- Modifications to the four-inch (0.1 m) utility pipeline to allow for lease PRC 421 processing, if PRC 421 recommissioning is approved;
- Installation of a pipeline from the seep tents to Platform Holly; and
- Other Platform Holly modifications.

A Therminol heating system would be installed on the platform to provide heat to the amine system, the LTS stabilizer system, the crude oil dehydration system, and the glycol gas dehydration system. Therminol is a synthetic heat transfer fluid that would be heated in a process heater or a cogeneration system and pumped through a closed loop system for the various heating needs on the platform. The Therminol system would be comprised of tanks, pumps and exchangers and would require an estimated 200 ft^2 (19 m^2) of deck space. A process heater would be used to supplement the heat gained from the cogeneration system. It would be sized to supply a maximum of 10 MMBtu/hr (10.5 billion joules/hr) and would be gas fired from the sweetened gas stream and the stabilizer gas. It would be equipped with a low NOx burner system.

Water treatment equipment would also be installed on the platform to remove entrained oils and solids from the produced water in preparation for injection into the Monterey formation through water injection wells. The water treatment skid would contain a hydrocyclone de-oiler, various tanks, pumps and filters.

The amine system would require de-ionized water. This system would utilize water transported to the platform from shore using the two-inch (0.05 m) utility pipeline (see Section 2.0, Project Description), and would prepare the water for use in the amine system.

The deck spacing of the produced water treatment and pumping equipment is estimated to be 400 ft^2 to 500 ft^2 (37 m^2 to 46 m^2).

As there may be production from onshore wells, such as the wells located at lease PRC 421, the four-inch (0.1 m) utility pipeline, which is currently used to transport fuel gas to Platform Holly for the flare pilots and purge, would be used to transport crude oil to Platform Holly for processing. Also, a 1,000 foot, eight-inch (305 m, 0.2 m) pipeline would be installed between the seep tents and Platform Holly to allow for processing of the seep gas at Platform Holly.

The platform support systems, such as deck drains, the emergency generator, lighting, controls, and monitoring would also be updated.

Platform Holly Power Generation

Power generation would be installed on Platform Holly to provide electrical power to the various equipment and motors. It is assumed that the same Jenbacher 6 series engines would be installed on Platform Holly that are proposed for the EOF or that two 4.8 MW gas turbine generator sets would be installed (as per the 2001 application). Estimated power generation would be about 10 MW. Heat produced from the cogeneration/waste heat units would total about 36 MMBtu/hr (38 billion joules/hr). The power generation would utilize the sales gas and the stabilizer gas as fuel.

The installation of power generation equipment on Platform Holly would most likely require the installation of combustion treatment systems, such as selective catalytic reduction (SCR) or the Catalytica Xonon systems for reduction of air quality impacts. SCR would require that urea be transported by supply boat in tote containers to the platform. Tote containers hold about 300 gallons (1.1 m^3), so at least one tote container would be required daily, for a total of about 470 tote containers per year. This assumes the full power production level of four generator engines, as detailed in Section 2.0, Project Description. If fewer engines are installed on the platform, urea consumption would decrease also.

Installation of different turbine technology, utilizing the Catalytica Xenon technology which is integrated into the Kawasaki GPB15x 1.5 MW turbines, for example, would enable the same low emissions levels without SCR treatment systems or ammonia/urea transportation requirements. The Kawasaki turbine generator would require about 150 ft^2 for the 1.5 MW GPB15x, which includes cogeneration and the catalyst system, and has demonstrated NOx levels less than 2.5 ppm.

The installation of power generation on the platform would provide electrical power that would not need to be transmitted to the platform and would provide efficient process heat for the Therminol system. However, it is possible, due to spacing and weight concerns on Platform Holly, that fewer than the proposed four power generation engines would be installed.

The spacing requirements for power generation for a smaller GE Jenbacher 3 Series engine would be about 200 ft^2 (19 m^2) per engine; whereas the Type 6 engines, as proposed in Section 2.0, Project Description, would require closer to 400 ft^2 (37 m^2) each. The Type 3 engines can generate about 1.1 MW each, as opposed to the Type 6 Series in the proposed Project, which generate 2.4 MW per engine. These engines would be equipped with cogeneration for the production of heat.

If less power generation is installed on Platform Holly, this would increase the process heater, and the transmission of more electricity from onshore.

Due to the possible need for SCR, the transportation requirements associated with moving the urea to the platform and the substantial weight associated with the installation of power generation on the platform (estimated at 300,000 pounds (lbs) to 400,000 lbs [136 kg to 181,000 kg]) for four Jenbacher Type 6 generator sets (GE 2007)), the power generation could be installed at the EOF, as per Section 2.0, Project Description, and the sales gas used as a fuel. The disadvantages of this option is that the heat recovery could not be used by the process (since the process equipment would be located on Platform Holly), thereby decreasing the efficiency of the system. Under this option, the stabilizer gas at Platform Holly would be used only in the process/Therminol heater offshore. The electricity generated at the EOF would be transmitted through the new offshore cable to Platform Holly (see Section 2.0, Project Description).

Another option is to not install any power generation, either on Platform Holly or at the EOF. The process/Therminol heat would be gained completely from a larger process heater burning the stabilizer gas and sweetened sales gas. This process heater would be sized to about 50 MMBtu/hr (53 billion joules/hr).

Both of these options would increase the electrical transmission requirements from the EOF to Platform Holly. As a result, some changes might be required in the proposed transmission cable replacement, such as a larger cable, and the substation at the EOF. However, these changes would not affect the installation description provided in Section 2.0, Project Description.

Platform Holly Jacket Modifications

The Platform Holly jacket and decking would most likely need to be strengthened under this alternative. The jacket is the support structure under the water that stands on the ocean floor. These modifications would include the following:

- Installation of an "exoskeleton" around the existing platform jacket;
- Installation of new piles placed into the ocean floor; and
- New deck extensions to increase existing deck space;

The extent of these installations would be a function of the equipment added to the platform, particularly if the power generation is installed on the platform. It is possible that fewer modifications would be required if no power generation, or a smaller power generation arrangement, is installed due to the weight of the power generator sets. This option might limit the extent of the jacket and deck extension modifications.

A structural evaluation of Platform Holly, conducted for the Applicant by Thomas and Beers (Thomas 2002), evaluated the ability of Platform Holly equipped with an external frame to handle the above listed additional loads, including the addition of power generation on the platform. The study concluded that Platform Holly can be successfully upgraded to carry the loads while simultaneously providing a greater margin of safety than exists for the current structural system.

Platform Holly Deck Spacing Requirements

Platform Holly deck space is limited without modifications, which could affect the seismic stability of the Platform jacket and potentially the viability of the lease extension application under Public Resource Code 6872. The 2001 application contained extensive information on the deck re-arrangement and configurations that would be required due to the above listed equipment additions. It concluded that, with jacket modifications, the above listed additions are technically feasible. The Applicant is currently performing a 1,000-year seismic analysis on the platform. The results of this analysis may indicate whether Platform Holly could withstand additional equipment.

The equipment additions discussed above and listed in Table 3-1 would require a net total deck space addition of about 5,500 ft^2 (557 m^2).

Platform Holly Energy and Utilities Requirements

Total platform electrical demand under this alternative is estimated to be 16 MW, due primarily to the production compression. Total heat demand is estimated to be 46 MMBtu/hr (49 billion joules/hr), which would be produced through a combination of the cogeneration/power generation systems and the process heater.

EOF Configuration

Under this alternative, equipment would be decommissioned and removed at the EOF, leaving only the following equipment:

- Oil storage tanks totaling 4,000 bbls (318 m^3) (the two existing oil storage tanks);
- Crude oil and gas pig receivers;
- Crude oil pumping and metering equipment;
- Final gas compression to pipeline pressures of 1,000 psig (6.9 MPa-g);
- The control building; and
- The electrical substation/switchgear building.

Final gas compression would utilize the existing gas compressor, with the modifications described in Section 2.0, Project Description, so that it could handle the additional gas. See Appendix C for a plot plan of the EOF under this alternative.

Construction Requirements: Labor, Equipment and Schedule

Labor requirements to modify the platform and install the equipment are summarized below:

- Marine labor force – 25 persons; and
- Platform labor force – 60 persons.

Work shifts would be seven days per week, 12 hours per day and all personnel would commute to the platform daily from the Ellwood Pier.

Equipment requirements would include marine supply boats to bring structural members and process components to the platform, a barge crane for larger equipment, diving vessels and crew transport. Requirements for each of these are listed below:

- Marine supply vessels – an estimated 100 trips over the course of the Project;
- Crane barge – two trips from Long Beach and a total of 54 days onsite;
- Diving vessels/support operations – two trips per week, for three weeks; and
- Crew boats – a total of 750 trips.

The offshore modifications are estimated to take a total of 15 months once appropriate approvals and permits have been secured.

Decommissioning and removal of equipment at the EOF would entail the following:

- Removal of the gas sweetening and sulfur recovery plant;
- Removal of the gas liquids storage tanks;
- Removal of the gas liquids process equipment, including the propane refrigeration system;
- Removal of the oil/water separation facilities;
- Removal of the water treatment facilities;
- Removal of the incinerators;
- Removal of the vapor recovery system;
- Removal of the Grace Membrane CO_2 removal systems; and
- Removal of other incidental piping, controls, monitoring and ancillary equipment.

Modifications at the EOF would not begin until after the Platform Holly modifications and new onshore crude oil pipeline have been completed. The general flow of work at the EOF would proceed as follows:

- Shut-down and purging of equipment;
- Removal of hazardous materials from equipment;
- Disassembly of equipment; and
- Transportation of equipment for re-use, scrap or recycle.

All staging, supply and assembly areas would utilize existing property at the EOF.

Approximately 80 to 100 personnel would be used during the peak period of decommissioning. Construction equipment would entail pickup trucks (three in number), welding rigs (six), gang trucks (two), compressors (two), large cranes (100 tons [two]) and a water truck, back hoe, dump truck, compactor, steam roller, manlift, and concrete saw.

The decommissioning would be expected to take approximately six months.

Required Agency Approvals

Agency approvals necessary under this alternative would be limited to approvals related to the EMT and EOF decommissioning and the offshore improvements and would include the following:

- CSLC;
- California Coastal Commission;
- California Department of Fish and Game;
- Regional Water Quality Control Board;
- City of Goleta;
- Santa Barbara County Air Pollution Control District, and
- Santa Barbara County.

3.3.4 Las Flores Canyon Processing: Offshore Gas and Onshore Oil Pipeline

Description

This alternative includes decommissioning the EMT and the EOF and would ship oil emulsion through a new onshore oil pipeline (as in the proposed Project and described in Section 2.0, Project Description) into the existing LFC facilities. There are two facilities in LFC; the Pacific Offshore Pipeline Company (POPCO) gas processing plant and the SYU gas and oil processing plant. Both are owned and operated by ExxonMobil.

Oil would be processed at SYU and then transported by the existing AACP. The SYU crude processing system has a capacity of 140,000 BPD (22,000 m^3) of crude oil emulsion and 100,000 BPD (16,000 m^3) of processed oil. It has recently been operating at about 38,000 BPD (6,045 m^3) of oil, so it is anticipated to have substantial crude oil processing capacity to handle the South Ellwood crude oil production.

A new, 10.6 mile (17 km) offshore gas pipeline would be constructed from Platform Holly to LFC. The new six-inch (0.15 m) gas pipeline would leave Platform Holly heading westerly in State waters within the Applicant's State lease PRC 3120. The route would continue westerly through State tidelands to a point offshore of the LFC where it would landfall through a 3,500 foot-long (1,067 m) directional drill. The directional drill would be made from the LFC parking area north of Highway 101 to an ocean outfall located approximately 2,500 feet (762 m) from shore, in water depths ranging between 35 feet to 50 feet (11 m to 15 m) below MSL.

The proposed six-inch (0.15 m) pipeline would enter a pig receiver at the LFC and then would enter the gas processing equipment at the POPCO facilities where it would be processed at either the POPCO gas plant or the SYU gas plant.

Installed adjacent to the gas pipeline would be a power cable which would transmit power to Platform Holly from the LFC location.

Gas processing would involve removing H_2S, CO_2 and gas liquids to produce pipeline quality natural gas.

POPCO

The current POPCO and SYU facilities process gas and oil produced offshore at Platforms Hondo, Heritage and Harmony. Both plants have gas processing equipment.

The SYU gas processing plant processes gas only for use in their cogeneration/power production facility and the POPCO facility processes gas for sale to The Gas Company. The two facilities are interconnected by pipelines. For example, all trucking of gas liquids takes place out of the SYU facility, since POPCO pipes gas liquids from the POPCO gas plant to the SYU facility.

POPCO began routine operations in 1984. POPCO currently is permitted for two processing limits: a maximum of 26,700 ppm (2.67 percent) H_2S in the inlet gas at an inlet processing rate of 60 MMSCFD (1.7 million m^3), and a maximum of 7,000 ppm (0.7 percent) H_2S in the inlet gas at an inlet processing rate of 75 MMSCFD (2.1 million m^3). In 2006, the monthly average amount of gas processed by POPCO ranged from 38 MMSCFD to 70 MMSCFD (1.1 million m^3 to 2.0 million m^3) with H_2S levels at about 3,600 ppm.

Sour gas is delivered to the POPCO Gas Plant facility through the pipeline from Platform Hondo. Some gas is diverted to the SYU plant and the remaining gas is treated first to remove condensate (consisting of natural gas hydrocarbon liquids and water); next to remove hydrogen sulfide using Sulfinol solutions; and finally compressed to natural gas transmission line pressures (approximately 1,000 psig to 1,100 psig). In addition, the plant contains a Sulfur Removal Unit ("SRU") process to convert the extracted hydrogen sulfide into elemental sulfur. The current capacity of the SRU is 60 LTD (65 metric tons) of elemental sulfur. Current sulfur removal at POPCO averages about 10 LTD to 12 LTD (11 metric tons to 13 metric tons). The elemental sulfur is sold and trucked out of the facility as a chemical by-product.

ExxonMobil Santa Ynez Unit

The SYU facility was constructed in 1993 to process crude oil and gas from Platforms Hondo, Heritage, and Harmony. The SYU gas plant is connected to the POPCO plant and processes gas to be used in the SYU electricity and steam generation units. The SYU gas plant has a capacity of 21 MMSCFD (0.6 million m^3), but is limited to 15 MMSCFD (0.4 million m^3) due to offshore pipeline capacity constraints. In 2006, the amount of gas processed by the SYU, on a monthly average basis, ranged from 7 MMSCFD to 11 MMSCFD (0.2 million m^3 to 0.3 million m^3).

Gas liquids extracted from the gas at POPCO are piped to the SYU for further processing. Over the last half of 2006, truck trips of gas liquids averaged 44 round trips per month with a high of 59 truck trips (Santa Barbara county data).

In the current design, produced gas from the SYU platforms is processed at POPCO. Produced crude oil emulsion and a portion of produced gas are processed at the SYU facility. Both facilities produce an acid gas stream containing H_2S and CO_2 as byproducts. This acid gas is routed to the two sulfur recovery units, one located at each facility (SYU and POPCO).

Modifications to LFC for South Ellwood Field Production

In order to utilize the POPCO or SYU gas processing facilities for Platform Holly gas, modifications would most likely need to be made to either facility to handle the additional maximum production of 20 MMSCFD (0.6 million m^3) of gas from Platform Holly. Modifications would most likely be required as the spare capacity of both plants combined is close to the estimated peak production from Platform Holly under the proposed Project drilling program. In 2006, the average spare capacity between the plants was 28 MMSCFD (0.8 million m^3) and the spare capacity during maximum operations was about 12 MMSCFD (0.3 million m^3) (SBCAPCD 2006).

No modifications would need to be made to handle additional crude oil, as the SYU facility is currently operating well below capacity. However, modifications would need to be made to the produced water handling at the SYU, as it is currently operating close to capacity. However, ExxonMobil is currently proposing modifications to their water handling system titled the Hondo Field Water Injection Project. ExxonMobil proposes to inject untreated produced water into the Hondo Field reservoir via the Harmony Platform instead of cleaning it up to a certain level and discharging it into the ocean. This would allow an increase in produced water handling from 75 to 90 thousand barrels per day. Additional modifications would most likely be required to the produced water handling systems in the future as the amount of produced water from the SYU facilities would be expected to increase over time. However, given the possible limitations on water injection at the SYU platforms (the SYU reservoirs can only handle a certain level of water injection), under this alternative, a pipeline would need to be routed from the LFC back to Platform Holly for injection of produced water at Platform Holly. Under this alternative, the produced water pipeline would most likely be installed alongside the onshore crude oil pipeline and would utilize the existing 4 inch (0.10 m) utility line between the EOF and Platform Holly.

Modifications to more fully integrate the SYU operations with the POPCO operations (both owned by ExxonMobil) were proposed in 2001 (SBC, 2001). This project was called the Synergy Project, but the application was subsequently withdrawn. The Synergy Project objective was to eliminate the problematic, high maintenance Stretford

Tail Gas unit at POPCO, integrate the two separate sulfur plants and tail gas units into a single sulfur plant at POPCO, and a single tail gas unit at the SYU for better operations and efficiency. This project was proposed because the facilities were operating substantially below their capacities in regards to sulfur recovery. The H_2S level in the gas had historically been below the levels that the facilities were designed for. Although this project was never implemented, it provides insight into the operations of the two facilities and the modifications that would be required in order to accommodate the Platform Holly production.

Modifications that might need to be made to the SYU and POPCO facilities to accommodate the Platform Holly production would include the following:

- Piping interconnects between the SYU gas processing plant and the POPCO processing plant to allow the SYU facilities to produce sales gas;
- Increased capacity of one or both plants, including replacement/expansion of amine equipment and/or replacement/expansion of LTS equipment;
- Installation of additional gas booster compressors to boost the pressure of the Platform Holly gas;
- Increased produced water handling and disposal capacity at LFC and SYU, including possible pipeline from LFC back to Platform Holly for water injection; and
- Modifications to permits to allow the processing of additional gas.

The exact extent of modifications would become available with further, more detailed discussion with ExxonMobil operations.

Based on information about the current operating levels at both plants, and the anticipated gas production levels from Platform Holly under the proposed Project, the commingled gas stream from the SYU Platforms (about 80 MMSCFD (2.3 million m^3) and 3,600 ppm H_2S), and Platform Holly (a maximum of 20 MMSCFD (0.6 million m^3) and 12,500 ppm H_2S) would have a gas throughput of about 100 MMSCFD (2.8 million m^3) and an H_2S level of about 5,500 ppm.

Consolidation Status

The LFC facilities (the POPCO and SYU facilities) are the only Santa Barbara county-approved consolidation site for southern Santa Barbara county oil & gas facilities. The Gaviota facility, located to the west of the LFC, has been re-designated a Consolidated Pipeline Terminal. Consolidation sites were established in 1987 as a result of the Advisory Measure B, approved by Santa Barbara county voters in 1985, which recommended that the Santa Barbara County Board of Supervisors consolidate all onshore industrialization at LFC and Gaviota. These consolidations were subsequently established in the Coastal Zoning Ordinances Section 35-154 in 1988, and later reiterated in Section 35-150.1 through Measure A96 in 1996. The ExxonMobil permit language, related to consolidation, reads as follows:

- ExxonMobil shall make its facilities and property available for consolidation and co-location of oil and gas facilities on a non discriminatory and equitable basis.
- In the event that the need for such facilities is demonstrated by other developers to the Planning Commission, ExxonMobil shall make available to such other developers any excess capacity of the SYU project facilities. In the event that sufficient excess capacity does not exist within the SYU project facilities to serve the needs of such other developers as demonstrated to the Planning Commission, ExxonMobil shall make its Las Flores/Corral Canyon property available to other developers for the construction of additional permitted oil and gas related facilities. In the event that such necessary facilities are not permittable pursuant to the County's consolidation policies, ExxonMobil shall reduce its throughput on a pro rata basis to accommodate such other developers.

Construction Requirements and Schedule

Construction of the offshore gas and onshore crude oil pipeline would be required at the LFC facilities. Modifications to the power cable and to Platform Holly, and decommissioning and abandonment of the EMT, as described in Section 2.0, Project Description, would still be implemented. The installation of the power generation, PSA system and other EOF modifications would not be implemented.

<u>LFC Modifications</u>

The extent and details of the modifications to the LFC facilities have not been developed; however, it is estimated that the construction equipment involved would include a 30-ton crane, backhoes, loaders, forklifts, air compressors, welding machines, generators, manlifts and a compactor (based on the Synergy proposal). It would take an estimated 10 to 20 workers, eight to 12 hours per day for a period of about three months.

Platform Holly and Offshore Improvements

Platform Holly modifications would be limited to connections with the gas pipeline, the new power cable from the LFC, possible installation of larger capacity gas compressors, and installation of new, larger capacity crude oil pumps. Otherwise, operations would be identical to proposed Project operations.

Offshore improvements would be constructed as indicated in Section 2.0, Project Description.

The seep gas would also need to be re-routed to Platform Holly. Produced water separated from the emulsion at Platform Holly would need to be injected at Platform Holly.

Crude Pipeline and Other Issues

Installation of the onshore crude oil pipeline is detailed in Section 2.0, Project Description. The new crude pipeline would tie-in directly to the existing Platform Holly to EOF pipeline. However, as there would no longer be crude storage, pumping or pigging operations at the EOF, the crude oil would be pumped directly from Platform Holly to the LFC crude storage facilities. This would most likely require installation of larger capacity pumps on Platform Holly. Platform Holly's existing pig launcher would be used. Installation of the produced water return pipeline would entail similar welding, pipeline handing and laying requirements as the crude oil pipeline installation, but would utilize the same trench and would be laid with the crude oil pipeline in a "bundle"..

Offshore Gas Pipeline.

Installation of the offshore gas pipeline would entail the following planning and construction activities:

- Pre-installation surveys;
- Modifications to Platform Holly;
- Barge laying of pipeline;

- Directional drilling at the LFC coastal location; and
- Tie-in to LFC facilities.

Pre-installation surveys would involve identification of ocean bottom features using multi-beam sonar, side scan sonar, and sub-bottom profilers to accurately determine the best pipeline route. Seafloor surveys would also identify sensitive areas (areas of hard bottom habitat) and/or man-made obstructions (wrecks, other pipelines, cables, etc.).

Modifications to Platform Holly would involve the tie-in of the pipeline to the existing platform gas pipeline. The new gas pipeline would utilize the existing Holly-EOF gas pipeline pig launchers, valves and equipment. Increased compression may be required to meet the higher POPCO inlet pressure of 1,000 psig.

Barge-laying of the pipeline would involve a lay barge approximately 300 feet to 400 feet (100 m to 130 m) long equipped with winches and anchor gear to ensure steady and precise movement along the pipeline laying route.

All pipe materials would be delivered to the barge by supply boats. The pipe would be assembled into a continuous string on the lay barge. Onshore staging areas for the loading of pipe onto supply vessels for shipment to the lay barge would be required and would most likely be located in Port Hueneme. An estimated 100 truck trips would be required to deliver the pipe to Port Hueneme. The pipeline would be placed on the ocean floor.

Directional drilling from LFC to the ocean outfall location would involve similar equipment as the DP Canyon directional drill described in the proposed Project Description, Section 2.0. The timeframe to install the directional drill is estimated to be 25 to 30 days, requiring a total of about 4,000 ft^3 (113 m^3) of drilling fluid.

It is estimated that the pipeline installation, including the directional drilling, would take about two months. Approximately 150 persons would be employed for offshore construction, and an additional 20 to 30 for installation of the directional drill at the LFC. Offshore equipment requirements would include cranes (two in number), welding machines (16), water pumps, compressors, x-ray equipment and winches. The directional drilling equipment requirements would be similar to those described in the proposed Project, Section 2.0, Project Description.

Decommissioning of the EOF

Decommissioning of the EOF would be similar to that described in the Processing on Platform Holly alternative described above, except that the crude oil tanks, crude oil pumping, metering equipment, pig receivers and launchers, and the electrical switchgear facilities would also be removed. The only facilities remaining at the EOF would be an underground valve box, which would allow for a valve to be located near the landfall of the Platform Holly to EOF pipeline. These modifications would add an additional month to the schedule described in the Processing on Platform Holly alternative.

Required Agency Approvals

Agency approvals necessary under this alternative would be limited to approvals related to the EMT decommissioning and the offshore improvements and would include the following:

- CSLC;
- California Coastal Commission;
- California Department of Fish and Game;
- Regional Water Quality Control Board;
- City of Goleta;
- Santa Barbara County Air Pollution Control District; and
- Santa Barbara County.

3.3.5 Las Flores Canyon Processing: Offshore Gas and Offshore Oil Pipeline

Description

This alternative would be identical to the above described alternative, except that the crude oil pipeline (and the water return pipeline) would be installed offshore, parallel to, and at the same time as, the offshore sour gas pipeline and power cable. Modifications to Platform Holly would be the same as above, except that the new emulsion pipeline would be tied in to the existing pig launchers on the Platform. The EOF would be completely abandoned. Modifications to the LFC would be the same as described above. The offshore pipelines would be installed as a bundle, along with a new power cable. Construction requirements would be similar as above, except that additional pipe would need to be transported and the number of welding stations would increase by approximately three.

This alternative would also require the seep gas pipeline to be re-routed from the EOF to Platform Holly. Produced water separated from the emulsion at Platform Holly would be injected at Platform Holly.

Required Agency Approvals

Agency approvals necessary under this alternative would be limited to approvals related to the EMT decommissioning and the offshore improvements and would include the following:

- CSLC;
- California Coastal Commission;
- California Department of Fish and Game;
- Regional Water Quality Control Board;
- City of Goleta;
- Santa Barbara County; and
- Santa Barbara Air Pollution Control District.